INTERMOUNTAIN POWER SERVICE CORPORATION

May 29, 2001

Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Attention: Milka Radulovic

Dear Director Sprott:

IPSC NOTICE OF INTENT: Transmittal of BACT Analysis

On April 4, 2001, Intermountain Power Service Corporation (IPSC) submitted a Notice of Intent (NOI) to modify the Intermountain Generating Station (IGS) in Delta, Utah. Pursuant to a request from the Division of Air Quality, we are herewith submitting a cursory Best Available Control Technology (BACT) analysis for that minor modification described in our NOI.

IPSC staff met with DAQ staff on April 9, 2001 to discuss the proposed project at IGS. As a result of that meeting, IPSC was requested to provide additional information, including a BACT analysis. With the enclosed report, all information requested by your staff has been provided. Accordingly, IPSC requests a fast track review of our NOI so that an approval order to construct can be issued as soon as practical.

The enclosed BACT report describes the economic and environmental consequences of several NOx control technologies. Since the IPSC modification is designed to be minor under PSD, the economics and environmental impacts of each have been analyzed in that light. The report comes to the logical and obvious conclusion for the single most appropriate control technology for this type of minor modification.

850 West Brush Wellman Road, Delta, Utah 84624 / Telephone: (435) 864-4414 / FAX: (435) 864-6670 / Fed. I.D. #87-0388573

If you or any one of your staff have any questions, please contact Mr. Dennis Killian, Superintendent of Technical Service, and 435-864-4414, or dennis-k@ipsc.com .

Cordially,

S Gale Chapman

S. Gale Chapman
President and Chief Operating Officer

RJC/BP/db
Enclosure

cc: Blaine Ipson, IPSC
Reed Searle, IPA
Mike Nosanov, LADWP

BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION FOR OXIDES OF NITROGEN

for

INTERMOUNTAIN POWER SERVICE CORPORATION
INTERMOUNTAIN POWER PLANT (DELTA, UTAH)
REVAMP PROJECT

Prepared for:

LOS ANGELES DEPARTMENT OF WATER & POWER
111 North Hope Street
Los Angeles, CA 90012

May 2001
740073

Prepared by:

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ACRONYMS

BACT	Best Available Control Technology
CO	Carbon Monoxide
CRF	Capital Recovery Factor
DAQ	State of Utah Division of Air Quality
EPA	United States Environmental Protection Agency
F	Fahrenheit
FGR	Flue Gas Recirculation
HP	High Pressure
IGS	Intermountain Generating Station
IPSC	Intermountain Power Service Corp
kW	Kilowatt
LADWP	Los Angeles Department of Water & Power
LNB	Low NOx Burner
LOI	Loss On Ignition
MMBtu	Million British Thermal Units
MW	Megawatt
NOI	Notice of Intent
NOx	Nitrogen Oxides
OFA	Overfire Air
O&M	Operating & Maintenance
ppm	parts per million
%	Percent
psi	pounds per square inch
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds

1.0 INTRODUCTION

Intermountain Power Services Corporation (IPSC) operates a two-unit coal-fired power plant, Intermountain Generating Station (IGS), in Delta, Utah. The Los Angeles Department of Water and Power (LADWP) is the "Operating Agent" of the facility and currently receives a significant amount of power generated by this power plant. IPSC proposes to revamp the power plant and increase power generation capacity by implementing a series of changes at the plant. IPSC prepared and submitted a Notice of Intent (NOI) on April 4, 2001 to the State of Utah Division of Air Quality (DAQ). The NOI is provided in Attachment 1. The DAQ has requested IPSC to prepare a limited BACT analysis for oxides of nitrogen (NOx), considering certain specific NOx control technologies.

LADWP retained Parsons Engineering Science (Parsons ES) to perform the BACT evaluation for the IPSC Power Plant. Parsons ES has evaluated the NOx control technology options as specified by DAQ to reduce NOx emissions. This report presents the results of the BACT evaluation study.

2.0 PROJECT DESCRIPTION

The IGS is a fossil fuel-fired steam-electric generating station that primarily uses coal as fuel for producing steam to generate electricity (SIC Code 4911). The IGS fires both bituminous and subbituminous coals. Fuel oil and used oil are also combusted for light off and energy recovery.

The IGS is a two-unit facility currently operating at a rated capacity of 875 megawatts (MW) per unit (gross). The project covered by this analysis will increase operating capacity to approximately 950 MW per unit. Approximately 5.6 million tons of coal and 600,000 gallons of oil (fuel oil and used oil) will be used each year at the new rate of production. Boiler operating capacity will be rated at 6.9 million pounds per hour of steam flow at 2,975 psi.

Each unit is dry bottom wall-fired. Dual register low-NOx burners were installed during the original construction of each unit around 1986-87. Table 1 shows the typical average fuel characteristics of the coal currently used at the power plant.

IGS has in place bulk handling equipment for unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes in this equipment are proposed. In addition, no changes in the usage of other raw materials or bulk chemicals are planned.

IPSC plans to enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This would involve replacing the HP blade section with a modified design that would improve performance and reliability.

TABLE 1
TYPICAL IPSC COAL
PHYSICAL AND CHEMICAL CHARACTERISTICS

Parameter	Actual Average
Heat Value	11,850 btu/lb
Moisture	8.5 %
Ash	9.2 %
Sulfur	0.52 %
Sodium	4 %
Grindability	46 HGI
%H2O	6.63 %
%C	67.82 %
%H	4.86 %
%N	1.31 %
%S	0.52 %
%O	10.08 %
Antimony	3.1 ppm
Arsenic	12 ppm
Barium	113 ppm
Beryllium	0.38 ppm
Cadmium	0.66 ppm
Chromium	24 ppm
Cobalt	2.9 ppm
Copper	7.8 ppm
Hydrogen Chloride	299 ppm
Hydrogen Fluoride	63 ppm
Lead	7.1 ppm
Manganese	9.9 ppm
Mercury	0.061 ppm
Nickel	4.7 ppm
Selenium	2.4 ppm
Vanadium	5.6 ppm
Zinc	7.4 ppm
Silicon Dioxide	65.2 %
Aluminum Oxide	17.5 %
Titanium Dioxide	0.8 %
Iron Oxide	3.3 %
Calcium Oxide	7.1 %
Magnesium Oxide	2.9 %
Potassium Oxide	1.5 %
Sodium Oxide	0.9 %
Phosphorus Pentoxide	0.2 %
Silica Equivalent Value	86.4 %
Base:Acid Ratio	0.15
Fusion Temperature (T250)	2900+ F

NOTE:
Data provided here are estimates only, based on available industry-wide information combined with specific analyses. These are not limits, but arithmetic means bounded by wide ranges of concentrations that are dependent on fuel source and type. Solid fuels naturally have wide variability in characteristics. This fuel information is in no way intended to represent binding fuel parameters.

Combined improvements to other areas of the plant would increase plant-generating capacity. These modifications would consist of "de-bottlenecking" critical points that presently prevent the full use of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes.

The existing pollution control devices at the power plant include dual register low-NOx burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The existing low-NOx burners provide a nominal 60% reduction in potential combustion NOx generation. The baghouse filters operate at nominal 99.95% efficiency. The wet sulfur dioxide (SO_2) scrubbers operate at nominal 90% efficiency. Control equipment for handling and transfer of solid material includes dust collection filters.

The proposed project includes modifications to the flue gas flow through scrubber modules to enhance SO_2 removal rates. Also, the project proposes replacing the existing dual register low-NOx burners with new technology low-NOx burners.

3.0 REGULATORY REQUIREMENTS

IPSC has completed and filed a Notice of Intent (NOI) with the DAQ for the proposed IGS project. Rule 307-401-6 provides the conditions for issuing an approval order in response to a NOI. R307-401-6(1) requires the source to apply Best Available Control Technology. Rule 307-413 lists available exemptions from the NOI and approval order requirements. Exemptions exist for de minimis Emissions, Flexibility Changes, Replacement-in-Kind Equipment and Reduction of Air Contaminants. However, these exemptions do not appear to apply to the IGS project as currently defined.

Utah R307-101-2 provides the definition of BACT as follows:

"Best Available Control Technology (BACT) means an emission limitation and/or other controls to include design, equipment, work practice, operation standard or combination thereof, based on the maximum degree or reduction of each pollutant subject to regulation under the Clean Air Act and/or the Utah Air Conservation Act emitted from or which results from any emitting installation, which the Air Quality Board, on a case-by-case basis taking into account energy, environmental and economic impacts and other costs, determines is achievable for such installation through application of production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall applications of BACT result in emissions of any pollutants, which will exceed the emissions allowed by Section 111 or 112 of the Clean Air Act."

In addition, R307-410-6 requires that permit approvals be granted only if the degree of pollution control is at least as good as BACT as defined above, except as otherwise provided in the rules. The federal Clean Air Act requires that BACT be installed on new major sources and major modifications of existing sources in attainment or PSD areas. There is no federal requirement for BACT on minor sources or minor modifications; therefore, the state minor source BACT requirement is more stringent than the federal requirement. It would appear that the requirement is contrary to Utah Code Ann. 19-2-106; however, IPSC provisionally feels that a BACT analysis for this particular project is not unreasonable. No other provisions in the State rules provide relief from BACT for minor modifications. Therefore, it appears that BACT must be applied.

Typically BACT is determined following the United States Environmental Protection Agency (EPA) "top-down" methodology in which all applicable technologies are considered and first evaluated on technological feasibility considerations for the specific application. Those that are not deemed to be technologically feasible are set aside. The remaining technologies are ranked in descending order starting with the highest possible control efficiency. An economic analysis is conducted for each of these with the results (cost-effectiveness) being reported in dollars per ton of emissions removed. The technology that has the highest cost-effectiveness meeting a specified regulatory threshold is then typically selected as BACT provided other considerations such as energy and other environmental impacts are deemed acceptable.

The DAQ specifies that the following criteria be considered in determining BACT (Reference 1):

1. Energy Impacts – especially focusing on any significant or unusual direct energy penalties that may be required on either an absolute or on an incremental basis.
2. Environmental Impacts – this should focus on non-air quality impacts (such as solid or hazardous waste generation or the discharge of polluted water) that may result due to the application of BACT; this analysis should also consider the generation of any toxic or hazardous air contaminants not regulated under the Clean Air Act.
3. Economic Impacts and Cost Calculations – in this analysis the costs of controls are quantified considering capital as well as operating costs.
4. Other Considerations – this allows the consideration of factors, not necessarily economic that may affect the selection of BACT including incremental cost-effectiveness, ability to control more than one pollutant, etc.

Based on prior discussions, the DAQ has indicated to IPSC that the BACT evaluation should be performed for only NOx emissions. Furthermore, rather than a full top-down analysis, IPSC has requested the consideration of five specific technologies for the BACT analysis. Finally, DAQ has indicated that the cost-effectiveness threshold for reasonable BACT for this minor modification is about $2,000 per ton of NOx removed. DAQ policy otherwise considers $5,000 per ton reasonable for major modifications.

4.0 BACT ANALYSIS

Parsons ES has evaluated the NOx BACT technology alternatives selected by IPSC and DAQ. Technologies considered include (1) ultra Low-NOx burners, (2) ultra Low-NOx burners with overfire air, (3) Mobotec Rotating Overfire Air (ROFA), (4) selective non-catalytic reduction (SNCR), and (5) selective catalytic reduction (SCR). Flue Gas Recirculation (FGR) was also initially considered as an applicable NOx control technology. While FGR is used frequently on gas-fired power plants, it is not considered a viable NOx control technology for coal-fired power plants. In fact, the EPA does not include FGR as a NOx control option for coal-fired power plants in its most recent edition of AP-42.

Each of the technologies selected for evaluation is briefly discussed below:

4.1 Ultra Low-NOx Burners – New generation low-NOx burners being considered will be similar to burners manufactured by Babcock and Wilcox (Model DRB-4Z), which are three stage burners. Additional details of these burners are presented in Reference 2. These burners were recently developed and are now in commercial use (Reference 2). Parsons estimates these burners can provide an additional 15% reduction in the NOx emissions at each IPSC unit. The estimated capital cost is approximately $5.2/kW. Fixed O&M costs are in the range of $0.035/kW-yr and variable O&M costs are negligible. These generic cost data are taken from vendor burner quotes and IPSC operating cost experience (Reference 8).

BACT Criteria Summary for Ultra Low-NOx Burners:

- Energy Impacts: Negligible compared to dual register Low NOx burners
- Environmental Impacts: A potential increase in CO emissions is likely along with the reduction in NOx emissions. Additional fuel use associated with the project will also result in a proportional increase in the emissions of CO, VOC and other toxic compound emissions
- Economic Impacts: Replacement costs
- Other Considerations: None

4.2 Ultra Low-NOx Burners with Overfire Air – When combined with overfire air (OFA), an even greater NOx reduction can be attained with ultra Low NOx burners (around 50%), possibly achieving 0.17 lb/MMBtu NOx emissions at full load. No significant energy penalties would result beyond new fan requirements. However, CO emissions may increase as NOx emissions are reduced to low levels. No data are available on the impacts on other air pollutant emissions such as that for VOCs or other air toxics – however, these are expected to mirror the increase in CO emissions. The estimated capital cost of these burners with overfire air is $11.6/kW. Fixed O&M costs are in the range of $0.048/kW-yr and variable O&M costs are in the range of $0.13/MWh. The capital costs were derived from vendor estimates provided by IPSC (Reference 8). Operating and maintenance costs were derived from IPSC experience with Low NOx burners and the costs associated with the fan (Reference 8). In addition, the use of ultra Low-NOx burners with overfire air can increase the Loss on Ignition (LOI). This increase in LOI may render the ash unsuitable for sale and may require disposal. Costs have been included from loss of revenue for the reduced ash sales and costs for subsequent ash disposal.

BACT Criteria Summary for Ultra Low-NOx Burners with overfire air:

- Energy Impacts: Additional fan use, lower efficiency due to potentially increased LOI
- Environmental Impacts: Additional ash disposal; higher CO, VOC and air toxics emissions
- Economic Impacts: Loss of ash sales; installation of new fans; higher fan cost, retrofit ductwork
- Other Considerations: None

4.3 MOBOTEC Rotating Overfire Air (ROFA) – This technology is primarily overfire air. However, computer modeling is performed on the combustion chamber to properly design the system. In ROFA, tangentially placed secondary air ports on opposite sides of the furnace rotate the volume of air and fuel creating extensive mixing and a cyclonic effect. Through the use of a booster fan the secondary air is introduced into the furnace at about 170 miles per hour creating a cyclone. This cyclonic rotation results in an excellent mixture of air and fuel providing a very efficient combustion process. The tangentially placed air ports are usually installed at a higher level in the furnace than the conventional over fire air ports.

The manufacturer claims that ROFA can provide a 50% reduction in NOx emissions – although this is likely from a base on uncontrolled NOx emissions. Since the IPSC units already have existing low-NOx burners, the extent of further NOx reductions have to be evaluated on a site-specific basis. Likely emissions reductions are thought to be below 50%. ROFA has been installed commercially at a few power plants. At the Carolina Power and Light Cape Fear Plant, ROFA has reduced NOx emissions from 0.60 lbs/MMBtu to 0.27 lbs/MMBtu while operating at 154 MW. This is the largest ROFA installation. Scaling this technology to the size of the IPSC units (i.e., to 950 MW each) is non-trivial since proper modeling and placement of the secondary air ports and resultant mixing is essential to achieve the claimed NOx reductions. Further, ROFA is designed for application to tangentially-fired or cyclonic boilers. ROFA used in wall-fired boilers may actually increase NOx emissions (Reference 8). As a result, this technology is still considered untested at units of this size and type, and, therefore, was eliminated from further consideration at this time. No cost estimates were developed for this technology.

4.4 Selective Non-Catalytic Reduction – SNCR uses ammonia (or a similar reducing agent such as urea) injection directly into the combustion chamber at a location of specified temperatures. The ammonia reacts with NOx directly in the gas phase to reduce NOx emissions. SNCR could provide a maximum of around 40% reduction in NOx emissions from current levels at IPSC. SNCR has been used and is considered a proven technology for coal-fired power plants, especially for base-loaded units such as IPSC. Minimal energy penalties are associated with SNCR, primarily relating to operating the ammonia injection system. SNCR does result in emissions of excess ammonia called ammonia slip. The ammonia slip is ammonia that has not reacted with the NOx. However, ammonia slip is a SNCR design parameter that can be set at a specific level, typically less than 5 ppm. The approximate installed capital cost for SNCR is $9-12/kW. Fixed O&M costs are estimated to be $0.11/kW-y and variable O&M costs are $0.356/MWh and can be higher depending on the cost of ammonia. Costs were based on information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Non-Catalytic Reduction:

- Energy Impacts: Negligible
- Environmental Impacts: Projected NOx reduction less than LNB with OFA. Additional SNCR results in ammonia emissions to the atmosphere from ammonia slip
- Economic Impacts: Annualized cost greater than LNB with OFA
- Other Considerations: Safety considerations associated with chemical transportation, storage, and handling

4.4 Selective Catalytic Reduction – SCR uses ammonia or some other reducing agent (but mostly ammonia) in the presence of a catalyst (located in a region of specified flue gas temperatures, typically 550°F to 900°F) to reduce NOx emissions. A 70-90% reduction in NOx is achievable with SCR, depending on the level of NOx present. A 75% NOx reduction may be possible at large coal-fired power plants such as IPSC. Like SNCR, SCR results in emissions of excess ammonia associated with the ammonia slip. SCR has now been used for several years on coal-fired power plants in Europe (Germany, Austria, Denmark, etc.), Japan, and in the US (since 1995). Several different SCR configurations have been used and validated (Refs 4, 5) including high-dust (where the catalyst is placed upstream of the air preheater and the particulate controls); low-dust (catalyst after the particulate controls), etc.

Designs can accommodate a wide variety of coals (including specific ash, moisture, sulfur, calcium and arsenic contents) and can achieve specified levels of ammonia slip using either anhydrous or aqueous ammonia. Currently, over 300 applications of SCR are planned at US power plants.

Indeed, current SCR implementation is limited from a schedule standpoint due to the large backlog of orders resulting in 52 weeks or more for delivery. However, discussions with SCR vendors have indicated that no SCR units are currently installed on power plants that combust coal with characteristics similar to the coal burned at IPSC (i.e., Utah coals). Thus, at this time, SCR is not considered a demonstrated technology.

SCRs do have potential energy penalties as they incur additional pressure drop and require additional power to operate. The approximate installed cost for SCR is $79/kW. Costs vary widely depending on the coal characteristics (since that affects the nature and amount of catalyst to be used), whether it is a new installation or a retrofit and the configuration of the control train. Fixed O&M costs are roughly $1.84/kW-yr for normal life installations and variable O&M costs are around $0.287/MWh. Costs were based on vendor data and information provided by IPSC (Reference 8).

BACT Criteria Summary for Selective Catalytic Reduction:

- Energy Impacts: Increased fan use to overcome pressure drop
- Environmental Impacts: Ammonia slip; waste disposal (spent catalyst)
- Economic Impacts: Estimated capital cost for SCR is 9.4 times the estimated capital cost of the entire IPSC improvement project
- Other Considerations: Long delivery times, incremental costs, currently not commercially demonstrated with Utah coal

IPSC's NOx emissions averaged 25,144 tons/year for the years 1999 and 2000. The total emissions are divided equally between the two identical units when averaged over two years. The proposed project without any NOx control would increase NOx by 2,816 tons/year for total NOx emissions of 27,960 tons/yr. A decrease in NOx emissions of 2,777 tons/year from the above value would result in a minor modification, which is defined as "an increase in NOx emissions to less than 40 tons/year."

Table 2 summarizes the estimated plant wide (i.e., both units) emissions reduction for each technology, the installed cost and the estimated cost per ton of NOx controlled. Details of the cost calculation are shown in Table 3. Incremental costs to meet minor modifications are also analyzed and presented. Table 4 provides the capital cost comparison for the base project and the base project with each NOx control technology studied.

TABLE 2
SUMMARY OF NOx CONTROL TECHNOLOGIES
FOR THE IPSC POWER PLANT
TWO 950 MW UNITS

TECHNOLOGY	ABSOLUTE EMISSION REDUCTION (TONS/YEAR)	INCREMENTAL EMISSION REDUCTION FOR MINOR MODIFICATION (TONS/YR)	INSTALLED COST (MM$)	ABSOLUTE COST EFFECTIVENESS ($/TON REMOVED) [2]	INCREMENTAL COSTS ($/TON REMOVED) [4]
Ultra Low NOx Burners	4,194	2,777	9.9	254	383
Ultra Low NOx Burners with Overfire Air	13,980	2,777	22.0	298	834
Rotating Overfire Air [1]	-		-	-	-
Selective Non Catalytic Reduction	11,184	2,777	18.4	634	1,192
Selective Catalytic Reduction	19,572	2,777	150.0	1,140 [3]	7,281

Notes:

[1] Not technologically demonstrated for this size and type of unit.
[2] See Table 3 for details.
[3] No operating installation on power plants that burn coal having the characteristics of the coal combusted at IPSC.
[4] Incremental Costs ($/ton) represent costs to only reach the minimum required NOx reduction of 2,777 tons in order to keep the proposed project a minor modification.

TABLE 3
COST CALCULATION DETAILS

Absolute Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Absolute Emission Factor (% reduction)	Absolute Emission Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Absolute Annualized Cost (MM$/yr)	Absolute Cost Effectiveness ($/ton removed)
LNB	27,960	15	4,194	9.9	0.035	0.056	0.000	0	25	9	0.1018	1.064	254
LNB w/OFA	27,960	50	13,980	22.0	0.048	0.078	0.131	1.853	25	9	0.1018	4.170	298
SNCR	27,960	40	11,184	18.4	0.111	0.179	0.356	5.042	25	9	0.1018	7.094	634
SCR	27,960	70	19,572	150.0	1.837	2.967	0.287	4.066	25	9	0.1018	22.304	1,140

Incremental Cost Evaluation

Technology	Pre-control NOx Emissions (tons/yr)	Minor Modification Emissions Reduction (tons/yr)	Capital Costs (MM$)	Unit Fixed O&M ($/kWh)	Total Fixed O&M (MM$/yr)	Unit Variable O&M ($/MWh)	Total Variable O&M (MM$/yr)	Life (yrs)	Interest Rate (%)	CRF	Incremental Annualized Cost (MM$/yr)	Incremental Cost for Minor Modification ($/ton removed)
LNB	27,960	2,777	9.9	0.035	0.056	0	0	25	9	0.1018	1.064	383
LNB w/OFA	27,960	2,777	22	0.048	0.078	0.131	1.853	25	9	0.1018	4.170	834
SNCR	27,960	2,777	18.4	0.111	0.179	0.089	1.259	25	9	0.1018	3.311	1,192
SCR	27,960	2,777	150	1.837	2.967	0.14	1.981	25	9	0.1018	20.219	7,281

Notes:

[1] Costs shown are for the total plant capacity of 1,900 MW.
[2] Estimated costs are vendor specific with adjustments based on EPA's CUE Cost Workbook provided by IPSC (Reference 8).
[3] Capital Cost adjustments are from direct vendor information provided by IPSC (Reference 8).

TABLE 4
CAPITAL COST COMPARISON

Technology	Technology Capital Cost (MM$)	Base Project (MM$)	Total Cost (MM$)	Cost Ratio (Total/Base)
LNB	9.9	16.09	25.99	1.62
LNB w/OFA	22.0	16.09	38.09	2.37
SNCR	18.4	16.09	34.49	2.14
SCR	150.0	16.09	166.09	10.32

5.0 CONCLUSION

Based on the regulatory requirements pertaining to NOx BACT, the various considerations that must be taken into account in the determination of BACT, and the reasonable cost-effectiveness thresholds used by DAQ, BACT for IPSC is discussed below:

Selective Catalytic Reduction
Given: 1) Extreme costs involved for adding SCR to keep this project a minor modification, 2) excessive costs when compared to project cost (see Table 4) for absolute NOx reductions, 3) additional ammonia emissions to the environment, 4) delivery times in excess of 52 weeks, and 5) likely technical difficulties to be overcome when applying SCR with Utah coal since there are no operating installations.
Determination: SCR as a retrofit NOx control technology is rejected.

Selective Non-Catalytic Reduction
Given: 1) Prohibitive costs (annualized) for both incremental and absolute NOx reductions, 2) NOx reductions less than LNB with OFA, and 3) additional ammonia emissions to the environment.
Determination: SNCR as a retrofit NOx control technology is rejected.

Rotating Over Fire Air
Given: ROFA is technically unproven for this size and type of unit.
Determination: ROFA as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners with Overfire Air
Given: 1) Increase in CO emissions to the environment, 2) increased loss on ignition (LOI) resulting in loss of ash sales revenue, 3) increase in land disposal of combustion wastes, and 4) high incremental cost for minor mod NOx removal.
Determination: LNB w/OFA as a retrofit NOx control technology is rejected.

Ultra Low-NOx Burners

Given: 1) Ease of replacement, 2) low cost of installation and operation, 3) a potential minor increase in CO emissions, and 4) moderate incremental cost for minor modification NOx removal.

Determination: Ultra low NOx burners as a replacement-in-kind NOx control technology is recommended as BACT for this project.

6.0 REFERENCES

1. Best Available Control Technology, policy guidelines from Utah DAQ, DAQ Website 2001.
2. First Commercial Application of DRB-4Z Ultra-Low NOx Coal Fired Burner, Bryk, S. A., et al, BR-1710, presented at Power-Gen International 2000.
3. Analyzing Electric Power Generation Under the CAAA, Appendix No. 5, EPA 1998.
4. Performance of SCR on Coal-Fired Steam generating Units, Acid Rain Program, EPA 1997.
5. States' Report on Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the OTAG, Appendix A, April 1996.
6. Proceedings from the FOMIS (Scientech) 1999 Winter Conference, "SNCR, SCR, And Gas Reburning - Technical Issues and Tradeoffs," James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
7. "Status Report on NOx Control Technology & Cost Effectiveness for Utility Boilers," Northeast States Coordinating Air Use Management Committee, June 1998. Prepared by James E. Staudt, Andover Technology Partners, Inc., 112 Tucker Farm Road, North Andover, MA 01845
8. IPSC, Transmittals from Rand Crafts to P. C. Tranquill consisting of data and information from Reaction Engineering of Salt Lake City, Utah; B&W of Barberton, Ohio; Cormetech, Inc. of Durham, North Carolina and Advanced Burner Technologies of Morgan, Pennsylvania, dated May 21, 2001 and May 22, 2001.

Attachment 1

Copy of NOI dated April 4, 2001

INTERMOUNTAIN POWER SERVICE CORPORATION

April 4, 2001

Richard Sprott, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Dear Director Sprott,

NOTICE OF INTENT: Modification of Source

Intermountain Power Service Corporation (IPSC) is hereby submitting a Notice of Intent (NOI) to increase generating capacity at the Intermountain Generating Station (IGS) in Delta. The IGS is a coal fired steam-electric plant located in Millard County, a NAAQS Attainment Area. Specifically, IPSC intends to construct modifications to Units One and Two at IGS to enhance performance and reliability and to allow increased capacity by de-bottlenecking certain aspects of our operation. This NOI requests an approval order to construct and a revision to IPSC's Title V permit to incorporate these modifications.

As required by UAC R307-401-2, the following information is provided:

(1) **PROCESS DESCRIPTION:** IGS is a fossil-fuel fired steam-electric generating station that primarily uses coal as fuel for the production of steam to generate electricity (SIC Code 4911). Both bituminous and subbituminous coals are utilized. Fuel oil and used oil are also combusted for light off and energy recovery.

IGS is a two unit facility operating at a rated capacity of 875 megawatts (MW) per unit (gross). Approximately 5.3 million tons of coal and 600,000 gallons of oil (including used oil) are used each year in the production of electricity. Boiler capacity is rated at 6.2 million pounds per hour of steam flow at 2822 psi.

IGS has in place bulk handling equipment for the unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes of this equipment are proposed. No changes in the usage of other raw materials or bulk chemicals are planned.

PROPOSED CHANGES: IPSC is planning to enhance steam flow characteristics through the high pressure (HP) section of each turbine used to generate electricity. This involves the replacement of the HP section with a modified design that improves performance and reliability. This modification in and of itself will not increase plant capacity, but will instead lower emissions due to decreased fuel use from the resulting increased performance.

Combined improvements to other areas of the plant will increase plant generating capacity. These modifications consist of "de-bottlenecking" critical points that presently prevent the full utilization of present equipment. Other changes are needed for reliability, performance and/or routine maintenance purposes. See Item 8 for details.

(2) **EMISSION CHARACTERISTICS:** The composition and physical characteristics of the emissions are expected to change as a result of the proposed modifications as indicated in the attached spreadsheet (Attachment 1), which shows the anticipated changes in emission rates, temperature, air contaminant types, and concentration of air contaminants. The mass flow of chimney effluent may change proportionately with the fuel usage and combustion at a heat input comparable to the current heat input. The existing pollution control devices include low-NOx burners, fabric filters and wet scrubbers.

(3) **POLLUTION CONTROL DEVICE DESCRIPTION:** The existing pollution control device equipment includes dual register low NOx burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. The existing low NOx burners provide a nominal 60% reduction in potential combustion NOx formation, the baghouse filters operate at nominal 99.95% efficiency, and the wet scrubbers operate at nominal 90% efficiency. Control equipment for the handling and transfer of solid material include dust collection filters.

The project includes modifications to the flue gas flow through scrubber modules to enhance SO_2 and acid gas removal rates. Also, the project includes installation of moderately improved NOx controls, such as the replacement of the existing dual register low NOx burners with new technology staged combustion low NOx burners.

(4) **EMISSION POINT:** The present emission point for the IGS boilers is a lined chimney that discharges at 712 feet above ground level (5386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude (UTM 4374448 meters Northing, 364239 meters Easting.).

(5) **SAMPLING/MONITORING:** Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide, and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt load). Monitoring will remain unchanged. Other emissions not directly monitored are calculated using engineering judgement, emission factors, and fuel analyses. The type and location of the monitors will not be changed.

(6) **OPERATING SCHEDULE:** IGS operates 24 hours per day, seven days per week. This will not change as a result of the proposed modifications.

(7) **CONSTRUCTION SCHEDULE:** Construction of the modifications will be performed in a staged manner, generally following the attached schedule. (See Attachment 2.)

(8) **MODIFICATION SPECIFICATIONS:** The changes covered by this NOI include:

- **High Pressure Turbine Retrofit:**

The high pressure turbine on each unit at IGS is scheduled to be replaced with a current technology, high efficiency turbine. This unit will increase high pressure turbine efficiency from approximately 84% to over 92%. Additionally, the turbine will be sized to provide up to 8.6% additional output.

- **Cooling Tower Performance Upgrade:**

The cooling towers on each unit at IGS are scheduled for performance enhancement modifications to increase heat rejection capacity. Also, cooling tower transformers feeding the cooling tower fan motors will be upgraded. A study will be performed to identify and resolve needed redundancy issues for operation at new output levels.

- **Boiler Safety Valve Additions:**
Currently, a review is underway focusing on existing boiler safety valve capacity. Addition of one main steam safety valve on each unit is expected in order to address reliability concerns with the existing valves and to accommodate planned increase in generation capacity.

- **Generator Cooling Enhancement:**
An engineering evaluation is currently underway to identify any enhancements required on the generator in order to accommodate the planned 8.6% increase in generator output. The anticipated result of this evaluation is an upgrade to the current generator and stator cooling systems.

- **Isophase Bus Cooling Enhancement:**
An engineering evaluation is currently underway to identify any enhancements required on the 26kv generator electrical bus feeding the main step-up transformer. The anticipated result of this evaluation is an upgrade to the current isophase bus duct cooling systems.

- **Large Motor Bus Loading Equalization:**
An engineering evaluation is currently underway to equalize the loading between the large and small motor bus. Due to limited tap adjustment capability on the auxiliary transformers feeding these load centers, several motors must be moved from one supply to the other in order to maintain required motor terminal voltages as unit output is increased.

- **Boiler Feed Pump Performance Upgrade:**
The boiler feed pump manufacturer has notified IPSC of several enhancements they now offer that address previous reliability concerns and allow for small increases in output. These include, improved bearing housings, flow path smoothing, and impeller clearance modifications. These modifications provide for increased pump output at acceptable reliability levels.

- **Main Step-up Transformer Cooling:**
The step-up transformer cores currently run close to their nominal temperature ratings when ambient temperatures are high. Proposed modifications are directed at increasing the cooling system capacity for cooling the transformer oil, core, and housing.

- **NOx Reduction Project:**
Some moderate NOx control systems will be added or enhanced. Recent advances in the burner industry have resulted in published operational data with improved NOx removal efficiencies. Within this project, burners in Unit 1 may be replaced with latest technology LNBs. Following successful testing, Unit 2 burner replacements would follow in successive outage upgrades. Alternatively, we may look at other technologies, or a combination of commercially available control systems. The installation of moderate NOx controls is expected to prevent any significant net increases of NOx due to increased capacity.

- **Scrubber Wall Ring:**
Scrubber wall ring technology has been developed and patented in recent years to address inefficient flow patterns that routinely develop within the absorber vessels. This ring would be installed within all twelve (12) scrubber absorber vessels to move flow back to the center of the vessel, providing more efficient SO_2 and acid gas scrubbing of the flue gas.

- **Generator Stator Cooling Water Oxygen Monitoring System:**
Given concerns in recent years regarding the long term integrity of the generator stator bars, an oxygen monitoring system, capable of early identification of stator bar degradation is essential. As load increases, stator bar temperature and cooling flow velocities are also expected to rise. This system will guard against unexpected degradation of the stator.

- **High Pressure Heater Drain Line Modifications:**
An existing resonant vibration occurring in the high pressure heater drain line to the deaerator has become an increasing concern. The vibration appears to increase with load. An increase in unit output would require a modification to eliminate this concern.

- **Boiler Modifications:**

A comprehensive study is currently underway with the manufacturer of the boilers (Babcock & Wilcox). This study has been designed to review all aspects of boiler operation at the new turbine output levels. This study includes evaluation of current technologies and operating practices for minimizing emissions. The study will provide recommendations for modifying the existing boilers for stable and efficient operation at the new higher rating.

- **Circulating Water Makeup Modifications:**

Current circulating water makeup capacity is inadequate for increased unit production. A new design will support increased makeup requirements and return a degree of redundancy to the system, as originally designed.

- **Boiler and turbine control system logic software & controls:**

Upgrade of the existing control system includes complete replacement of the plant information system, control system simulator, coordinated control system, turbine control systems, combustion control systems and the alarm indication system. The new control systems will eliminate parts availability and reliability issues as well as providing the increased control system capacity required for the projects associated with the increased unit output. Boiler and turbine operating parameters are controlled within closer tolerances, resulting in less upsets and better emission control.

The capital expenditures for these changes to both units is expected to be about $35 million. More detailed engineering specifications and project descriptions can be provided as needed.

PRODUCTION SUMMARY: The proposed project will increase generation capacity from 875 to approximately 950 MWhe, with steam flow design increasing from 6.2 to 6.9 million pounds per hour. Design heat input will increase from 8,352 to 9,225 million BTU per hour, requiring an increase from 5.3 to 5.6 million tons of coal each year. See Attachment 1 for details.

- **ADDITIONAL INFORMATION:** IGS operates under a Title V permit (#2700010001). IPSC intends to continue to operate in full compliance with that permit and applicable requirements. No deviations from permit conditions are expected. IPSC requests that this NOI also be considered a request for revision of the Title V permit, and requests that the conditions of the approval order be incorporated into the Title V permit once the approval order is issued.

Operating Flexibility
IPSC reserves the right to cancel any and all planned modifications at any time. IPSC may only install the turbine dense packs, which by themselves would not require review as a major modification. We note that EPA has previously determined that enhancements like the Dense Pack project are not major modifications if there is no significant net increase in emissions. (See letter from Francis X. Lyons, Regional Administrator, EPA Region 5 to Henry Nickel of Hunton & Williams, dated 5/23/00.) If IPSC decides to install only the Dense Pack enhancements and certain upgrades for reliability, IPSC will provide the supporting information to show that there will be no significant net increase in emissions.

Phased Permitting
Due to the length and intermittent nature of the construction schedule for the proposed modifications, IPSC requests that the approval order contain terms that take into account the phases of installation. For example, due to lead times for engineering and budgeting, some portions of the project which affect capacity and/or emissions may be installed prior to upgrades in pollution control equipment. IPSC would be receptive to an approval order that includes interim emission limits for the period prior to project completion and final upgrades to control equipment.

Permit "Off Ramps"
Budgeting for the proposed project will be considered on a fiscal year-by-year basis. Although the current business climate for increased capacity is very favorable for this project, outlooks may change. Accordingly, IPSC proposes that the approval order contain conditions which provide that pollution control upgrades will be required only if those "debottlenecking" projects go forward which, if installed without controls, would increase the potential to emit enough to require major modification review. If IPSC decides not to complete certain portions of this project, the approval order should be structured so that IPSC is not forced to proceed with project completion.

NSPS/PSD Applicability

New Source Performance Standards (NSPS). The proposed modifications do not trigger NSPS applicability under 40 CFR Part 60, Subpart Da. NSPS pollutants for this facility are NOx, SO_2 and PM10. A modification is defined for NSPS purposes to include any change in operation of a source that increases the maximum hourly emissions of a Part 60 regulated pollutant above the maximum achievable rate during the previous five years. See 40 CFR 60.14(h).

Prevention of Significant Deterioration. Planned upgrades to pollution control equipment as part of this proposed modification will result in net emissions decrease for certain criteria pollutants as a result of the project. Other pollutants may have increases below PSD significant levels. Accordingly, this modification will not require a major modification review. IPSC is providing to the DAQ supporting calculations and operating data.

Should you require any additional information, please contact Mr. Dennis Killian, Superintendent of Technical Services, at (435) 864-4414, or dennis-k@ipsc.com.

In as much as this notice of intent also constitutes a request for revision of IPSC's Title V Operating Permit, I hereby certify that, based on information and belief formed after reasonable inquiry, the statements and information in this document and the accompanying attachments are true, accurate, and complete.

Cordially,

S. Gale Chapman

S. Gale Chapman
President, Chief Operations Officer, and Title V Responsible Official

Attachments: Excel Spreadsheets (Emissions)
Time Line Project Gantt Chart
IPSC Check, $1,20[illegible].00 NOI Fee

cc: Blaine Ipson, IPSC
Jerry Hintze, IPSC
Bruce Moore, LADWP CES
Mike Nosanov, LADWP
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Reed Searle, IPA
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Tim Conkin, LADWP CES
John Schumann, LADWP
James Holtkamp, LLG&M

INTERMOUNTAIN POWER HP TURBINE DENSE PACK PROJECT							ATTACHMENT 1: Worksheet A	
NOI / PSD Calculations								
Operating & Production								
Parameter	Average Value	UoM	Post-Change Value					
Rated Output	875	Mwhe	950					
Fuel Use (Coal)	5,264,292	tons/yr	5,578,473					
Plant Operating Time	16,386	Unit hours	16,386					
Heat Value	11,872	BTU/lb	11,872					
Heat Input (Actual)	7,628	MMBtu/hr	8,083					
Heat Input (Design)	8,352	MMBtu/hr	9,225					
Heat Rate	9,564	Btu/KWhr	9,475					
Flow - Stack	125,000,000	scfh	133,000,000					
Emissions								
Parameter/Pollutant	2 Yr Average Value	UoM	Post-Change Value	Change+/-	PSD Significance Levels	PSD Major Trigger Value	Difference (Trigger - Post)	PSD Triggered?
PSD								
SO2	3586.31	Tons	3513.10	-73.21	40	3626.31	-113.21	N
SO2 % Removal	93.62	%	93.88					
NOx	25143.97	Tons	24346.10	-797.87	40	25183.97	-837.87	N
CO	1317.06	Tons	1394.60	77.54	100	1417.06	-22.46	N
PM10	273.77	Tons	283.51	9.75	15	288.77	-5.25	N
Lead	0.087	Tons	0.123	0.036	0.600	0.687	-0.564	N
VOC	12.65	Tons	13.40	0.75	40	52.65	-39.25	N
Beryllium	0.0102	Tons	0.0014	-0.0088	0.0004	0.0106	-0.0092	N
Mercury	0.081	Tons	0.105	0.024	0.100	0.181	-0.076	N
Fluorides (HF)	9.70	Tons	10.16	0.46	3	12.70	-2.54	N
Sulfuric Acid	4.06	Tons	4.05	-0.01	7	11.06	-7.01	N

ATTACHMENT 1: Worksheet B

PSD / NSPS Observations

Plant Emissions - Criteria Pollutants

	SO2 (tons)	SO2 % Removal	Nox (tons)	CO (tons)	PM10 (tons)	Lead (lbs)	VOC (lbs)	Beryllium (lbs)	Mercury (lbs)	Fluorides (HF) (lbs)	Sulfuric Acid (lbs)
1996	3759	92.28	19688	1080	83	224		3.57	270	19139	*
1997	5076	92.05	22675	1291	108	263		4.17	323	22905	*
1998	4281	92.67	25708	1321	114	167		2.23	331	23436	8443
1999	3698	93.57	24179	1312	249	156	25394	2.18	123	19167	8234
2000	3474	93.67	26109	1322	299	191	25204	1.89	201	19621	8015
5 Year Avg	4058	92.8	23672	1265	171	200	25299	2.81	250	20854	8230
Last 2 yr Avg	3586	93.6	25144	1317	274	174	25299	2.03	162	19394	8124
TRIGGER: Average + Sig. incr	3626		25184	1417	289	1374	105299	2.83	362	25394	22124
Projected Actuals	3513	93.88	24346	1395	284	245	26809	2.76	211	20313	8109

Plant Operational Data

	Coal Usage (tons)	Plant Operating Hours	Btu/lb Coal HV	MBTU/hr Avg Heat Input	LB/MMBtu NOx Emission rate	lbs/hr NOx Emission Rate	LB/MMBtu SO2 Emission Rate	lbs/hr SO2 Emission Rate		Maximum NOx Emission Rate (Last 5 years)	Maximum SO2 Emission Rate (Last 5 years)
1996	4310562	15359	11860	6657	0.39	2564	0.07	489		6045	1150
1997	5156967	16564	11789	7343	0.37	2738	0.08	613		4875	1333
1998	5278344	16683	11823	7481	0.41	3082	0.07	513		5331	1279
1999	5244703	16462	11858	7550	0.39	2938	0.06	449		5007	1456
2000	5283790	16309	11885	7701	0.42	3202	0.06	426		5441	1379
5 Year Avg	5055271	16275	11843	7348	0.39	2905	0.07	498	Max.-Prev. 5 yrs.	6045	1456
Last 2 Year Avg	5264292	16386	11872	7628	0.40	3070	0.06	438	Proposed Average:	2972	429
Projected Actuals	5578473	16386	11843	8064	0.37	2972	0.05	429	Proposed Max:	4613	1384

OPERATING CHANGES

	Actual Max Heat Input	Design Max Heat Input (MMBtu/hr)	Fuel Use (coal, tons)	Heat Rate	Mlbs/hr Steam	Mwhe	Stack Flow (scfh)
Present Operation	7628	8352	5264291.5	9564	6.1	875	125,000,000
Proposed Operation	8083	9225	5,578,473	9475	6.9	950	133,000,000

ASSUMPTIONS

All increases / decreases based on coal use only. Fuel oil & other bulk chemical chemical use not expected to change.
Estimated 15% nominal reduction with new NOx controls over old.
Estimated 4% nominal removal efficiency improvement in scrubber efficiency.
HAPs PSD triggers calculated per UDAQ Dispersion Modeling Guidelines at R307-410-4
VOC's calculated from HAPs list.
Projected nominal efficiency improvement: 8.8%
Projected nominal capacity improvement: 8.5%
Projected heat input / coal usage increase: 5.9%
Projected uncontrolled NOx increase: 11.2%

HAPs / Other Projection Data - COAL									ATTACHMENT 1: Worksheet C	
POLLUTANT	Concentration (ppm)	Pollutant Emission Factor (lbs/10^12 Btu)	Release Rate	ACGIH TLV	Units	ETF	ETV	TSL	Difference	Modeling Review?
Metals										
Antimony	3.1	0.92*(C/A*F	0.0002725	0.5	mg/m3	0.368	0.184	0.016666667	-0.1837275	
Arsenic	12	3.1*(C/A*F	0.001230335	0.01	mg/m3	0.123	0.00123	0.000111111	3.34976E-07	Y
Barium	113	((	0.010102368							
Beryllium	0.38	1.2*(C/A*(	1.22205E-05	0.002	mg/m3	0.123	0.000246	2.22222E-05	-0.00023378	
Cadmium	0.66	3.3*(C/A*(	0.000887876	0.01	mg/m3	0.123	0.00123	0.000111111	-0.000342124	
Chromium	24	3.7*(C/A*F	0.002617514	0.05	mg/m3	0.123	0.00615	0.000555556	-0.003532486	
Cobalt	2.9	1.7*(C/A*F	0.000508172	0.02	mg/m3	0.368	0.00736	0.000666667	-0.006851828	
Copper	7.8	((	0.000817929							
Lead	7.1	3.4*(C/A*F	0.002259576	0.05	mg/m3	0.368	0.0184	0.001666667	-0.016140424	
Manganese	9.9	3.8*(C/A*F	0.003322407	0.1	mg/m3	0.368	0.0368	0.003333333	-0.033477593	
Mercury	0.061		0.002975759	0.025	mg/m3	0.368	0.0092	0.000833333	-0.006224241	
Nickel	4.7	4.4*(C/A*P	0.000364871	0.1	mg/m3	0.368	0.0368	0.003333333	-0.036435129	
Selenium	2.4		-8.977E-05	0.2	mg/m3	0.368	0.0736	0.006666667	-0.07368977	
Vanadium	5.6	((	-0.044629974							
Zinc	7.4	((	0.000372181							
Organics										
Acenaphthene		0.00000051	9.77863E-06							
Acenaphthylene		2.5E-07	4.79344E-06							
Acetaldehyde@		0.00057	0.010929053	25	ppm C	0.31	13.96267894	4.50408998	-13.95174988	
Acetophenone@		0.000015	0.000287607	10	ppm	0.368	18.08392638	1.63803681	-18.08363877	
Acrolein@		0.00029	0.005560395	0.1	ppm C	0.31	0.071078119	0.022928425	-0.065517723	
Anthracene		0.00000021	4.02649E-06							
Benzene@		3.8 (lbs/10^	0.00171811	0.5	ppm	0.368	0.587821677	0.053244717	-0.586103567	
Benzo(a)anthracene		8.0E-08	1.5339E-06							
Benzo(a)pyrene		0.0018 (lbs/10^	8.13841E-07							
Benzo(b,j,k)Fluoranthene		1.1E-07	2.10912E-06							
Benzo(g,h,i)perylene		2.7E-08	5.17692E-07							
Benzyl chloride@		0.0007	0.013421643	1	ppm	0.368	1.90517137	0.17256987	-1.891749727	
Biphenyl@		0.0000017	3.25954E-05	0.2	ppm	0.368	0.464176687	0.04204499	-0.464144092	
Bis(2-ethylhexyl)phthalate (DEHP)@		0.000073	0.001399686							
Bromoform@		0.000039	0.000747777	0.5	ppm	0.368	1.902462168	0.172324472	-1.90171439	
Carbon disulfide@		0.00013	0.002492591	10	ppm	0.368	11.45992638	1.03803681	-11.45743379	
2-Chloroacetophenone@		0.000007	0.000134216	0.05	ppm	0.368	0.116337669	0.010537832	-0.116203452	
Chlorobenzene@		0.000022	0.000421823	10	ppm	0.368	16.94154601	1.534560327	-16.94112419	
Chloroform@		0.000059	0.001131253	10	ppm	0.368	17.96803272	1.627539196	-17.96690147	
Chrysene		0.0000001	1.91738E-06	L	ppm	0.368	#VALUE!	#VALUE!	#VALUE!	
Cumene@		0.0000053	0.000101621	50	ppm	0.368	90.44973415	8.192910702	-90.44963253	
Cyanide		0.0025	0.047934441							
2,4-Dinitrotoluene@		0.00000028	5.36866E-06							
Dimethyl sulfate@		0.000048	0.000920341	0.1	ppm	0.368	0.189794683	0.017191547	-0.188874342	
Ethyl benzene@		0.000094	0.001802335	100	ppm	0.368	159.7827403	14.4730743	-159.780938	
Ethyl chloride@		0.000042	0.000805299	100	ppm	0.368	97.10985685	8.796182686	-97.10905155	
Ethylene dichloride@		0.00004	0.000766951	10	ppm	0.368	14.89459305	1.349147921	-14.8938261	
Ethylene dibromide@		0.0000012	2.30085E-05	L	ppm	0.368	#VALUE!			
Fluoranthene		0.00000071	1.36134E-05							
Fluorene		9.1E-07	1.74481E-05							
Formaldehyde@		3.0 (lbs/10^	0.001356402	0.3	ppm	0.123	0.04532135	0.00409407	-0.043964947	
Hexane@		0.000067	0.001284643	500	ppm	0.368	648.5529652	58.7457396	-648.5516806	
Indeno(1,2,3-cd)pyrene		6.1E-08	1.1696E-06							
Isophorone@		0.00058	0.01112079	5	ppm	0.31	8.761779141	2.826380368	-8.750658351	
Methyl bromide@		0.00016	0.003067804	1	ppm	0.368	1.429104294	0.129447853	-1.42603649	
Methyl chloride@		0.00053	0.010162101	50	ppm	0.368	37.99656442	3.441717791	-37.98640232	
5-Methyl chrysene		2.2E-08	4.21823E-07							
Methyl ethyl ketone@		0.00039	0.007477773	200	ppm	0.368	217.0372188	19.65916837	-217.029741	
Methyl hydrazine@		0.00017	0.003259542	0.01	ppm	0.368	0.006934053	0.000628085	-0.003674511	
Methyl methacrylate@		0.00002	0.000383476	50	ppm	0.368	75.35345603	6.825494206	-75.35307256	
Methyl tert butyl ether@		0.000035	0.000671082	40	ppm	0.368	53.08230675	4.808179959	-53.08163567	
Methylene chloride		0.00029	0.005560395	50	ppm	0.368	63.91460123	5.789366053	-63.90904083	
Naphthalene@		0.000013	0.000249259	10	ppm	0.368	19.29403681	1.747648262	-19.29378755	
Phenanthrene		0.0000027	5.17692E-05							
Phenol@		0.000016	0.00030678	5	ppm	0.368	7.082306748	0.641513292	-7.081999968	
Propionaldehyde@		0.00038	0.007286035							
Pyrene		0.00000033	6.32735E-06							
Tetrachloroethylene		0.000043	0.000824472	25	ppm	0.368	62.38691207	5.650988412	-62.38608759	
Toluene@		1.4 (lbs/10^	0.000632988	50	ppm	0.368	69.33300613	6.280163599	-69.33237315	
1,1,1-Trichloroethane		0.00002	0.000383476	350	ppm	0.368	702.8423722	63.66325835	-702.8419887	
Styrene@		0.000025	0.000479344	20	ppm	0.368	31.35450307	2.8400818	-31.35402372	
Xylenes@		0.000037	0.00070943	100	ppm	0.368	159.7827403	14.4730743	-159.7820309	
Vinyl acetate@		0.0000076	0.000145721	10	ppm	0.368	12.95751329	1.173687798	-12.95736757	
[illegible]										
Total PCDD/PCDF		0.000002 (lbs/10^	9.04268E-10							
Acid Gases										
Hydrogen Chloride	299		0.009981802							
Hydrogen Fluoride	63		0.056113641							
Sulfuric Acid	0.50%	0.0646	0.000180978							

NOTES: Emission Calculations

(1) By ash fraction derivative
(2) By stack test
(3) By EPRI's Trace Report
(4) By SoCo's Paper

Realized HAP emission increases calculated per Utah R307-410-4.

To convert ppm to mg/m3: TLV(ppm) X MW / 24.45

z = Impact (acute/chronic/carcinogenic)

ETF = Emission Threshold Factor (Table IV-2, R307-410-4, Boundaries >100m)

TLV = Threshold Limit Values (ACGIH 2001 version)

ETV = Emission Threshold Value ([lb/hr] = [TLV] X [ETF])

TSL = Toxic Screening Level (TLV/z)

MW = Atomic molecular weight of compound

@ = VOC

IP10_003509

	HP TURBINE DENSE PACK SO2 PROJECTIONS					ATTACHMENT 1: Worksheet D		
	99-00 Average lbs/mmbtu							
	inlet	stack	% reduction					
	0.7744	0.0494	93.6209		U1/U2 '99-00 average			
	0 7744	0.0474	93.8760		4% reduction stack lbs/mmbtu			
	0 7744	0.0204	97.3657		97 3657% reduction (4% increase in scrubber efficiency)			
	1999							
	Unit One				Unit Two			
	Coal Burned (tons)	2,472,213			Coal Burned (tons)	2,772,580		
	Heating Value btu/lb	11,858			Heating Value btu/lb	11,858		
	Inlet SO2 lbs/mmbtu	0.7963			Inlet SO2 lbs/mmbtu	0.7867		
	Stack SO2 lbs/mmbtu	0.0479			Stack SO2 lbs/mmbtu	0 0538		
	Inlet Tons SO2	23,343.93			Inlet Tons SO2	25,864.54		
	Stack Tons SO2	1,404.21	1,566.40	(EDR)	Stack Tons SO2	1,768.80	2,131.80	(EDR)
	% Removal (lbs/mmbtu)	93.9847			% Removal (lbs/mmbtu)	93.1613		
	% Removal (tons)	93.9847			% Removal (tons)	93.1613		
	% Removal (EDR tons)	93.2899	0 69		% Removal (EDR tons)	91.7578	1 40	
	2000							
	Unit One				Unit Two			
	Coal Burned (tons)	2,799,081			Coal Burned (tons)	2,484,709		
	Heating Value btu/lb	11,885			Heating Value btu/lb	11,885		
	Inlet SO2 lbs/mmbtu	0.7712			Inlet SO2 lbs/mmbtu	0.7432		
	Stack SO2 lbs/mmbtu	0.0482			Stack SO2 lbs/mmbtu	0.0477		
	Inlet Tons SO2	25,655.57			Inlet Tons SO2	21,947.27		
	Stack Tons SO2	1,603.47	1,855.10	(EDR)	Stack Tons SO2	1,408.62	1,619.20	(EDR)
	% Removal (lbs/mmbtu)	93.7500			% Removal (lbs/mmbtu)	93.5818		
	% Removal (tons)	93.7500			% Removal (tons)	93.5818		
	% Removal (EDR tons)	92.7692	0 98		% Removal (EDR tons)	92.6223	0 96	
	1999-2000 Average Intermountain Generating Station							
	% Removal (lbs/mmbtu)	93.6194			Inlet lbs/mmbtu	0.7744		
	% Removal (tons)	93.6194			Stack lbs/mmbtu	0.0494		
	% Removal (EDR tons)	92.6098	1 01					
	Dense Pack - Intermountain Generating Station							
	PREMODIFICATION	1999 - 2000 Average (calculated)			POST MODIFICATION (W/O Scrubber Modification)			
	Coal Burned (tons)	5,268,249			Coal Burned (tons)	5,578,473		
	Heating Value btu/lb	11,871			Heating Value btu/lb	11,871		
	Inlet SO2 lbs/mmbtu	0.7744			Inlet SO2 lbs/mmbtu	0.7744		
	Stack SO2 lbs/mmbtu	0.0494			Stack SO2 lbs/mmbtu	0.0494		
	Inlet Tons SO2	48,430.50	54,170.45	Actual	Inlet Tons SO2	51,282.36	57403.69	Actual Projected
	Stack Tons SO2	3,089.45	3586.25	(EDR)	Stack Tons SO2	3,271.37	3797.47	(EDR Projected)
	% Removal (lbs/mmbtu)	93.6209	93.38		% Removal (lbs/mmbtu)	93.6209	93.68	
					POST MODIFICATION (W/Scrubber Modification)			
		Tons of SO2 Reduction			4% reduction stack lbs/mmbtu			
		130.85			Coal Burned (tons)	5,578,473		
		73.15	(EDR Projected)		Heating Value btu/lb	11,871		
					Inlet SO2 lbs/mmbtu	0.7744		
					Stack SO2 lbs/mmbtu	0.047424		
					Inlet Tons SO2	51,282.36	57403.69	Actual Projected
					Stack Tons SO2	3,140 51	3,513.10	(EDR Projected)
					% Removal (lbs/mmbtu)	93.8760	93.88	
					POST MODIFICATION (W/Scrubber Modification)			
		Tons of SO2 Reduction			97.3657% reduction (4% increase in scrubber efficiency)			
		1,920.44			Coal Burned (tons)	5,578,473		
		2074.06	(EDR Projected)		Heating Value btu/lb	11,871		
					Inlet SO2 lbs/mmbtu	0.7744		
					Stack SO2 lbs/mmbtu	0.0204		
					Inlet Tons SO2	51,282.36	57403.69	Actual Projected
					Stack Tons SO2	1,350.93	1,512.19	(EDR Projected)
					% Removal (lbs/mmbtu)	97.3657		
NOTES:								
1	Stack SO2 tons calculated from lbs/mmbtu are less than SO2 tons calculated for EDR from CEM SO2 ppm and Stack flow.							
2	Dense Pack SO2 tons are calculated from lbs/mmbtu (yellow boxes)							

ATTACHMENT 1: Worksheet E

CO Calculations

Dense Pack - Intermountain Generating Station				
PREMODIFICATION	1999 - 2000 Average		POST MODIFICATION	
Coal Burned (tons)	5,268,249		Coal Burned (tons)	5,578,473
CO E.F. (lb/ton)	0.50		CO E.F. (lb/ton)	0.50
CO Emissons (tons)	1317.06		CO Emissons (tons)	1394.62

Tons of CO increase
77.56

AP-42 Table 1.1-3

DENSE PACK PM10
COAL USAGE CALCULATION SUMMARY

ATTACHMENT 1: Worksheet F

YEARLY INVENTORY

5,578,473	Tons coal received Railcar Unloading
5,578,473	Tons of coal fed to both Units
2,789,237	Tons of coal fed to Unit 1
2,789,237	Tons of coal fed to Unit 2
11,800	Coal heating value (Btu/lb)
25.1	Coal pile (acres)
0.0056	Unit 1 Particulate lbs/mmbtu (tsp)
0.0036	Unit 2 Particulate lbs/mmbtu (tsp)

UNIT 1 FABRIC FILTER PARTICULATE EMISSION (online)
169.5677 TPY Particulate PM10 AP 42 Table 1.1-6

UNIT 2 FABRIC FILTER PARTICULATE EMISSION (online)
109.0078 TPY Particulate PM10 AP 42 Table 1.1-6

COAL TRAIN UNLOADING DUST COLLECTORS A,B,C,D
0.0625 TPY Particulate PM10

COAL TRUCK UNLOADING DUST COLLECTOR
0.0000 TPY Particulate PM10 Included in train unloading

COAL RESERVE RECLAIM DUST COLLECTOR
0.0020 TPY Particulate PM10 10% of Coal Crusher Emissions

COAL SAMPLE PREPARATION DUST COLLECTOR
0.0000 TPY Particulate PM10

COAL TRANSFER BUILDING #1 DUST COLLECTOR
0.0156 TPY Particulate PM10

COAL TRANSFER BUILDING #2 DUST COLLECTOR
0.0312 TPY Particulate PM10

COAL TRANSFER BUILDING #4 DUST COLLECTOR
0.0195 TPY Particulate PM10

COAL CRUSHER BUILDING DUST COLLECTOR
0.0195 TPY Particulate PM10

ACTIVE COAL STACKOUT (fugitive)
3.9049 TPY Particulate PM10

DUST COLLECTOR 13A & 13B
0.0312 TPY Particulate PM10

DUST COLLECTOR 14A & 14B
0.0156 TPY Particulate PM10

COAL PILE FUGITIVE EMISSIONS
0.8368 TPY Particulate PM10

283.5145 TPY PM10 (COAL ONLY)

COMMENTS
EF found in AP-42 Table 11.19.2-1 site dust collectors for coal, limestone, lime vacuum sys. and soda ash PM10 and PM2.5.
Using same ratio of PM10 to PM2.5 found with emissions at stack.
Use cumulative Mass % <= Stated Size in AP-42 Table 1.1-5 for percentages of PM10 and PM2.5 as a ratio of TSP.
PM10 = 92% of TSP
PM2.5 = 53% of TSP

ATTACHMENT 2

Uprate Project Coordination

Task Name	Start	Finish
Unit 2 Projects	1/2/2001	4/1/2004
HP Turbine Retrofit	1/15/2001	4/1/2002
Cooling Tower Performance Upgrade	2/1/2001	4/1/2004
Boiler Safety Valve Addition	4/2/2001	4/1/2002
Generator Cooling Enhancements	4/2/2001	4/1/2002
Isophase Cooling Enhancements	4/2/2001	4/1/2002
Large Motor Bus Loading Equalization	4/2/2001	4/1/2002
Boiler Feed Pump Performance Upgrade	1/2/2001	4/1/2003
Main Step-up Transformer Cooling	3/1/2001	4/1/2002
NOx Reduction Project	4/2/2001	4/1/2004
Scrubber Wall Ring	5/2/2001	4/2/2003
Generator SCW O2 Monitoring	4/2/2001	4/1/2002
HP Heater Drain Line Mods	4/2/2001	4/1/2002
Boiler Modifications	4/2/2001	4/1/2004
Cooling Tower Makeup Modifications	1/2/2002	4/1/2004
Cooling Tower Electrical Redundancy	1/2/2002	4/1/2004
Unit 1 Projects	1/2/2001	4/2/2003
HP Turbine Retrofit	1/15/2001	4/1/2003
Cooling Tower Performance Upgrade	2/1/2001	4/1/2003
Boiler Safety Valve Addition	3/1/2001	4/1/2003
Generator Cooling Enhancements	1/2/2002	4/2/2003
Isophase Cooling Enhancements	1/2/2002	4/2/2003
Large Motor Bus Loading Equalization	1/2/2002	4/1/2003
Boiler Feed Pump Performance Upgrade	1/2/2001	4/1/2003
Main Step-up Transformer Cooling	1/2/2002	4/1/2003
NOx Reduction Project	3/1/2001	4/1/2003
Scrubber Wall Ring	5/1/2001	4/1/2003
Generator SCW O2 Monitoring	1/2/2002	4/1/2003
HP Heater Drain Line Mods	4/2/2001	3/1/2002
Boiler Modifications	4/2/2001	4/1/2003
Cooling Tower Electrical Redundancy	1/2/2002	3/31/2003

Printed: 4/3/2001
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IGS Uprate Project Coordination (Actual Construction Dates)

Task Name	Start	Finish
Unit 2 Projects (Design & Construction)	**1/2/2001**	**4/1/2004**
HP Turbine Retrofit	2/25/2002	4/1/2002
Cooling Tower Performance Upgrade	2/1/2002	4/1/2004
Boiler Safety Valve Addition	2/25/2002	4/1/2002
Generator Cooling Enhancements	2/25/2002	4/1/2002
Isophase Cooling Enhancements	2/25/2002	4/1/2002
Large Motor Bus Loading Equalization	2/25/2002	4/1/2002
Boiler Feed Pump Performance Upgrade	2/1/2002	4/1/2003
Main Step-up Transformer Cooling	2/25/2002	4/1/2002
NOx Reduction Project	2/1/2004	4/1/2004
Scrubber Wall Ring	2/1/2002	4/1/2003
Generator SCW O2 Monitoring	2/25/2002	4/1/2002
HP Heater Drain Line Mods	2/25/2002	4/1/2002
Boiler Modifications	2/1/2004	4/1/2004
Cooling Tower Makeup Modifications	1/2/2002	4/1/2004
Cooling Tower Electrical Redundancy	1/2/2002	4/1/2004
Unit 1 Projects (Design & Construction)	**1/2/2001**	**4/2/2003**
HP Turbine Retrofit	2/25/2003	4/1/2003
Cooling Tower Performance Upgrade	2/1/2002	4/1/2003
Boiler Safety Valve Addition	2/25/2003	4/1/2003
Generator Cooling Enhancements	2/25/2003	4/1/2003
Isophase Cooling Enhancements	2/25/2003	4/1/2003
Large Motor Bus Loading Equalization	2/25/2003	4/1/2003
Boiler Feed Pump Performance Upgrade	2/1/2002	4/1/2003
Main Step-up Transformer Cooling	2/25/2003	4/1/2003
NOx Reduction Project	2/25/2003	3/26/2003
Scrubber Wall Ring	2/1/2002	4/1/2003
Generator SCW O2 Monitoring	2/25/2003	4/1/2003
HP Heater Drain Line Mods	2/1/2002	4/1/2002
Boiler Modifications	2/25/2003	4/1/2003
Cooling Tower Electrical Redundancy	1/2/2002	4/1/2003
Cooling Tower Makeup Modifications	1/2/2002	4/1/2003

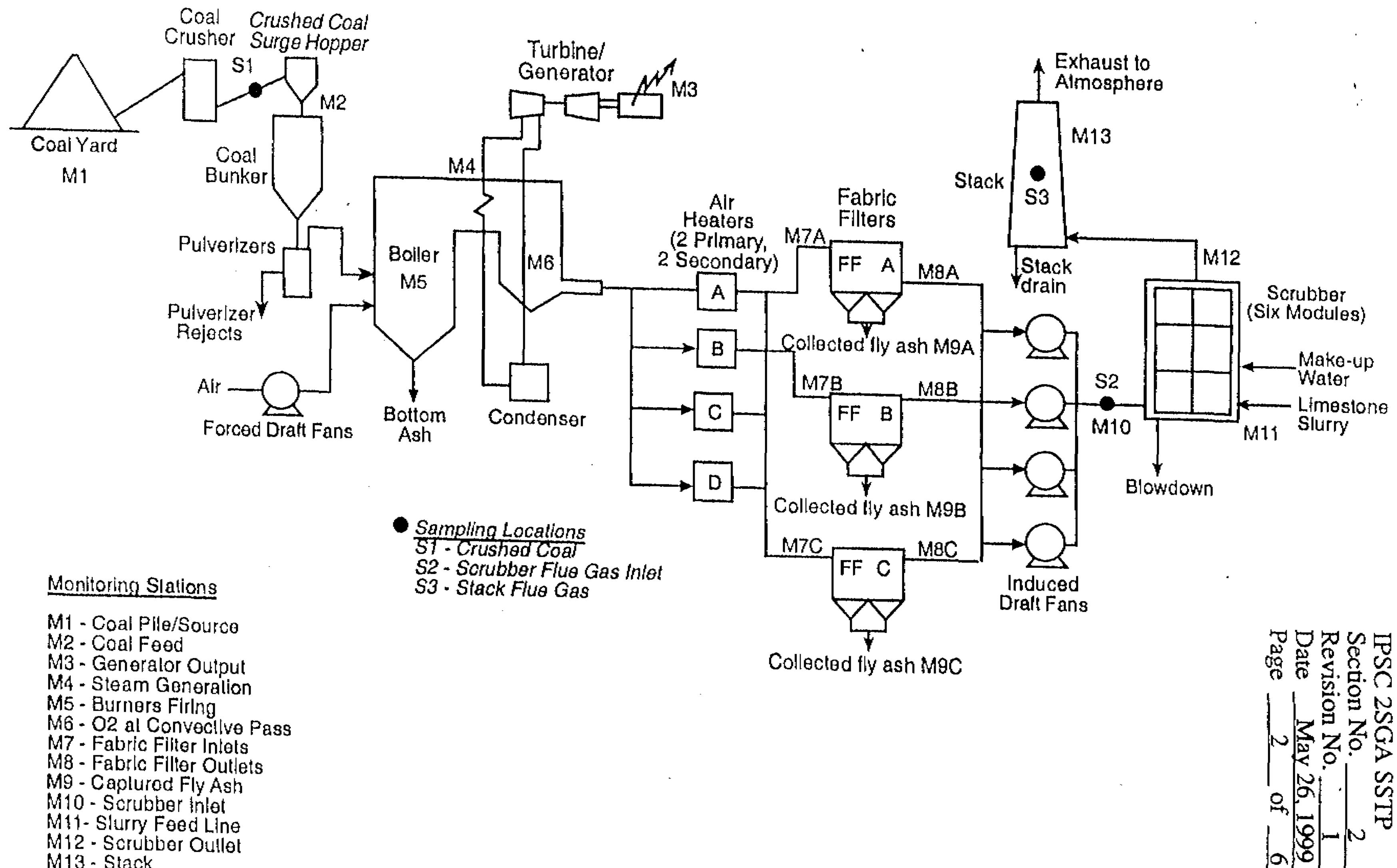
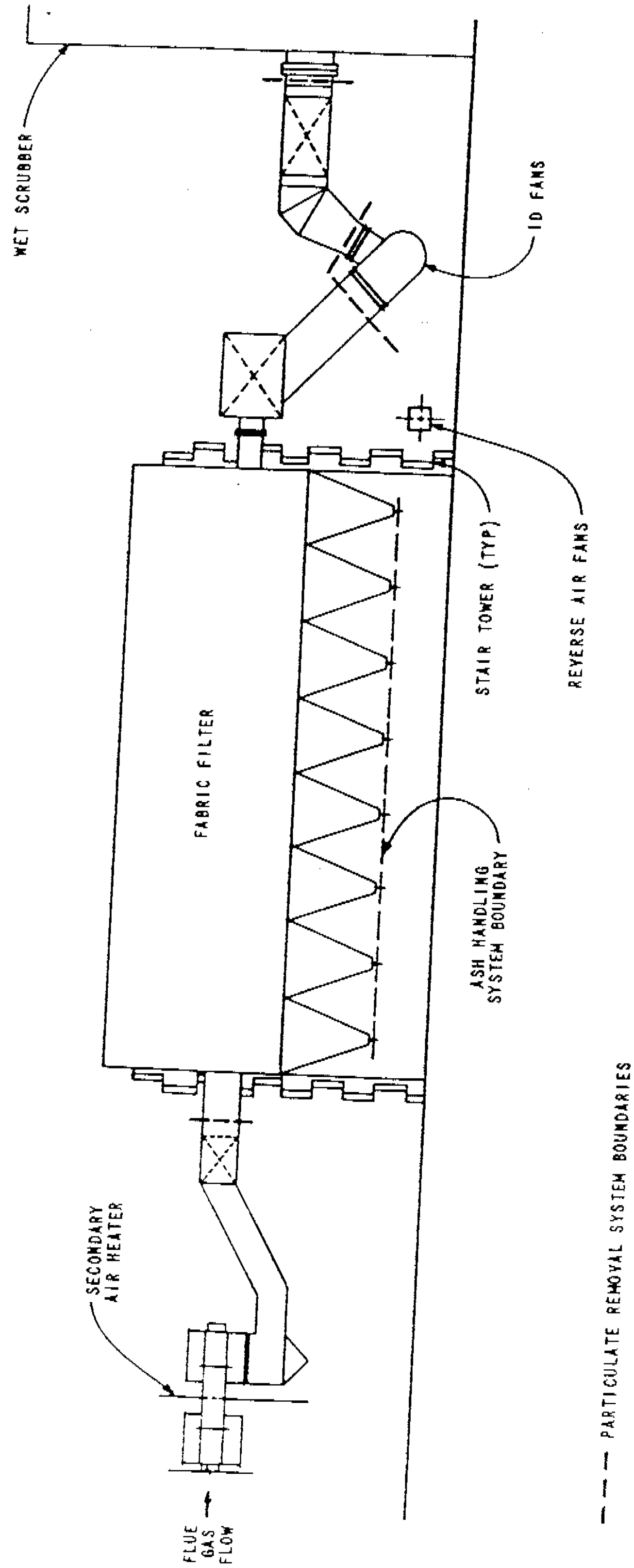
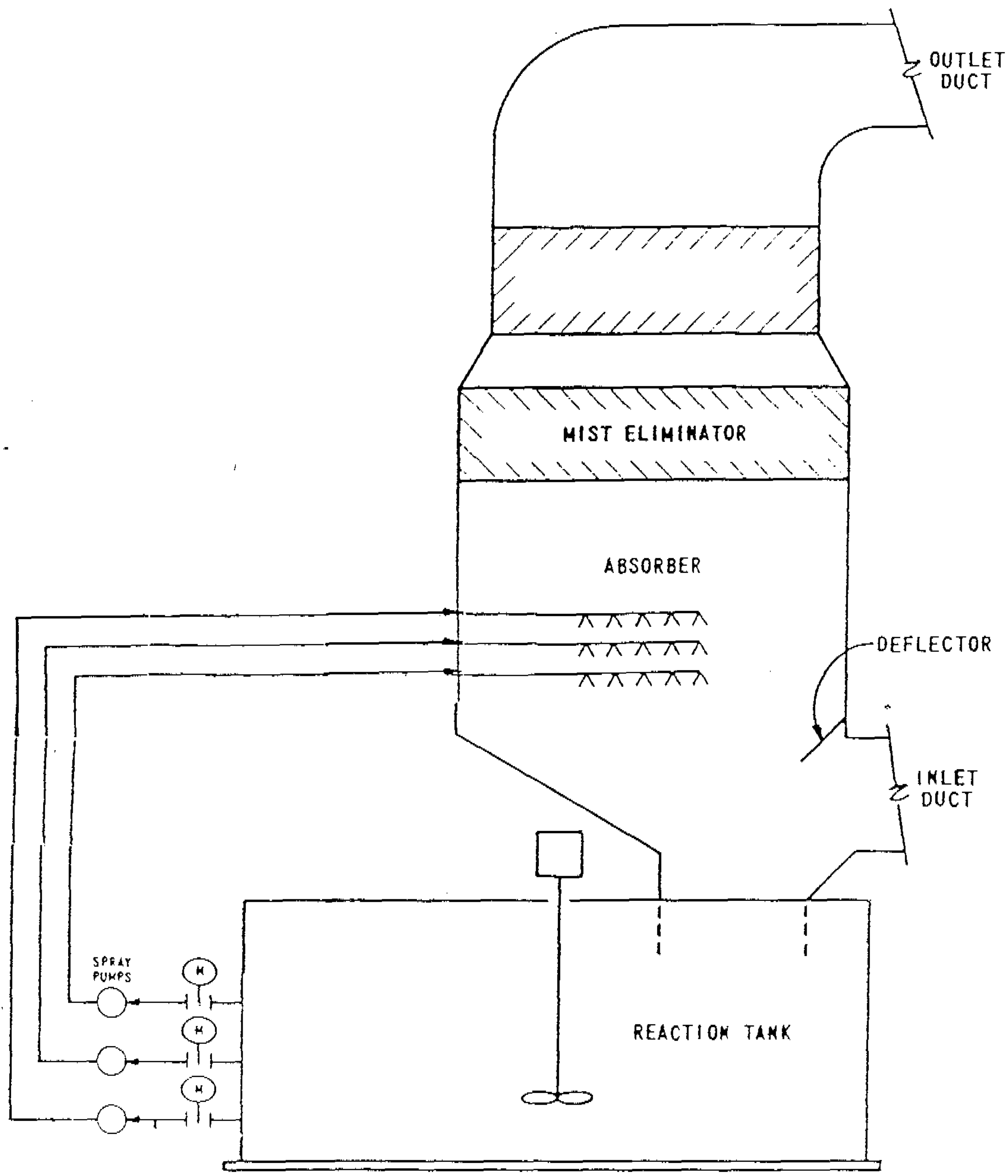


Figure 2-1. Intermountain Power Plant Boiler 2SGA process overview.



PARTICULATE REMOVAL SYSTEM ARRANGEMENT ELEVATION
FIGURE 2-1



TYPICAL SCRUBBER MODULE
FIGURE 3-1